

# UNDERVOLTAGE LOAD SHEDDING

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## **I. INTRODUCTION**

This paper discusses why voltage as well as frequency load shedding may be necessary to prevent major system blackouts. Investigations of recent blackouts [1,3,7] indicate that the root cause of almost all of these major power system disturbances is voltage collapse rather than the underfrequency conditions prevalent in the blackouts of the 1960 and '70s. This paper explores the nature of recent power system blackouts (2003 east coast, 1996 California and others) and explains why voltage collapse is the leading edge indicator of impending power system problems. It also discusses the design and security issues that need to be addressed in the design of an undervoltage load shedding (UVLS) scheme and why relying on underfrequency load shedding (UFLS) may be "too little, too late." The paper addresses the current level of UVLS on utility systems as well as current NERC (North American Electric Reliability Council) pronouncements on the subject.

## **II. WHY VOLTAGE COLLAPSE IS THE CAUSE OF RECENT BLACKOUTS**

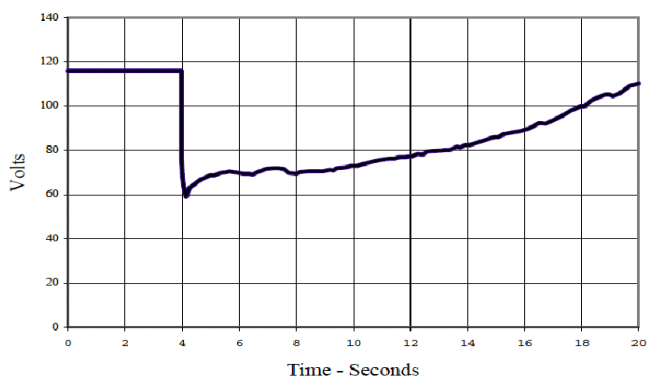
Power systems today are much more susceptible to voltage collapses than they were 35 years ago as we increasingly depend on generation sources that are located remotely from load centers. Generators in eastern Canada and the midwestern U.S. provide large amounts of power to east coast load centers such as New York City. Generators in Washington, Oregon and western Canada provide substantial power to southern California. Two factors promote generation that is remote from load centers:

- The economics of purchasing power from lower-cost remote sources rather than more expensive local generation
- The public's reluctance or refusal to permit new generating plants to be built in urban high-load areas, causing utilities/IPPs to build these plants remote from these load centers

These two fundamental changes in operation of the U.S. power grid result in the transmission of power over long distances. This makes the power grid very dependent on the transmission system to deliver power to the load centers. It also results in increased reactive power losses when transmission lines trip.

Another key factor that results in rapid system voltage collapse is the nature of the loads that are being served by utilities. Many of today's loads are single-phase small air conditioning motors. This was not the case 35 years ago when air conditioning was not as prevalent. These small motors are prone to stall when subjected to voltage dips caused by transmission system short circuits. During hot weather, these motors comprise a high percentage of the utility load. The slow tripping of stalled motors and the relatively slow re-acceleration of more robust motors result in low system voltage after a transmission system fault is cleared [2]. The voltage dip and its effect on these motors are exacerbated if the transmission system fault is cleared via a time delay backup relay or is a multi-phase fault. Such a slow-clearing fault resulted in the voltage collapse that caused a blackout of the city of Memphis in 1987 [3].

Fig. 1 shows an example of voltage recovery for a Phoenix area transmission system fault incident that occurred in July 1995 during hot weather.



Voltage stay below 80% for 8 seconds after fault cleared.

Source: Jhon A. Diaz de LeonII, Carson Taylor, 'Understanding and Solving Short-Term Voltage Stability Problems'

Residential Voltage Recovery for Phoenix Area Incident on July 29, 1995

Fig. 1 Example of Delayed Voltage Recovery Resulting from a Transmission Fault

Fig. 2 illustrates a basic power system with the remote generators supplying a significant amount of power ( $P_s$ ) over a considerable distance to the remote load center. The load is comprised of resistive load and motor load. During a voltage dip, resistive load current will decrease and help limit the need for local reactive support. Motor loads are essentially constant kVA devices. The lower the voltage, the more current they draw—increasing the need for local reactive (VAR) support. Power systems loads consist of both resistive loads as well as reactive motor loads. During hot weather, however, air conditioning motor loads comprise a large portion of total load, thereby making the system more susceptible to voltage collapse.

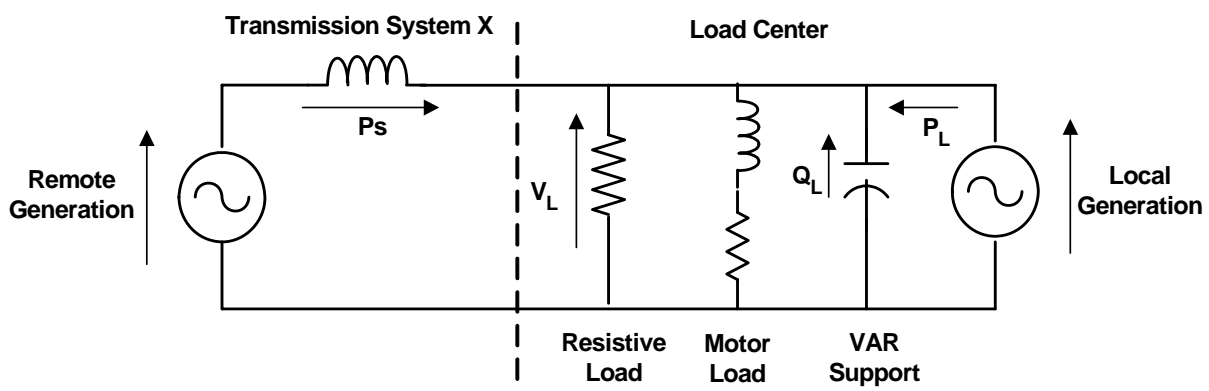


Fig. 2 Basic Power System

Reactive power (VARs) cannot be transmitted very far, especially under heavy load conditions, and so it must be generated close to the point of consumption. This is because the difference in voltage causes VARs to flow and voltages on a power system are only typically +/- 5% of nominal. This small voltage difference will not cause substantial VARs to flow over long distances. Real power (MW) can be transmitted over long distances through the coordinated operation of the interconnected grid, whereas reactive power must be generated at, or near, the load center.

Since VARs cannot be transmitted over long distances, the sudden loss of transmission lines results in the immediate need for local reactive power to compensate for the increased losses of transporting the same power over fewer transmission lines. If that reactive support is not available at the load center, the voltage will go down. For these reasons, voltage—rather than frequency—has become the key indicator that the power system is under stress. Utilities recognize that frequency can remain normal as voltage sags to a low level prior to a complete system collapse and are implementing UVLS schemes to complement their existing underfrequency load shedding programs.

### **III. TYPES OF POWER SYSTEM INSTABILITIES DURING SYSTEM DISTURBANCES**

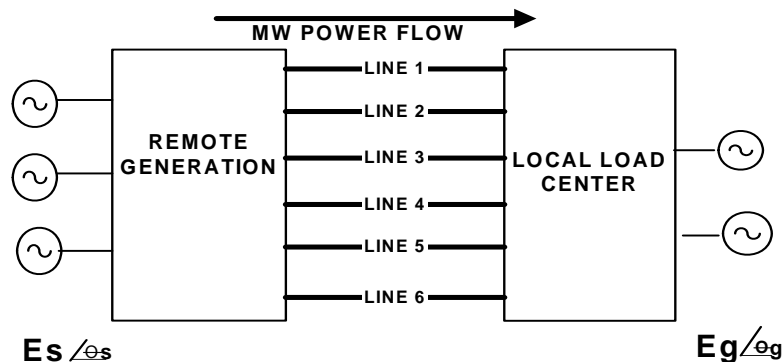
#### *A. Basics – Voltage vs. Frequency Stability*

In a power system, frequency is a measure of the balance of MW generation and MW load. When MW generation and MW load are exactly in balance, the frequency is at the normal level of 60 Hz. When load exceeds generation, the frequency goes down. The rate of decline depends on the inertia of the generators within the system. Under normal conditions, there are slight changes of frequency when load suddenly increases or generation trips off-line which results in a slight (hundreds of a hertz) reduction in frequency until the aggregate generation in the system can be increased to meet the new load condition. If there is a large negative unbalance between MW load and MW generation, the frequency is reduced. UFLS schemes on the utility system are designed to restore the balance by shedding load.

Voltage is a measure of the balance of MVAR load and MVAR capability within a power system. If that reactive support is not available, the voltage goes down. Reactive power system support can only come from two sources: shunt capacitors and generators/synchronous condensers. Shunt capacitors are a double-edged sword. They do provide reactive support, but they also generate fewer VARs as the voltage dips. The VAR output of a capacitor bank is reduced by the square of the voltage. Shunt capacitor banks cannot quickly adjust the level of reactive power.

Generation at the load center can provide a dynamic source of reactive power. As the voltage goes down, the generator can quickly provide increased reactive support within its capability limits. Unlike shunt capacitors, the amount of reactive support does not drop as system voltage goes down. The amount of reactive power is controlled by the generator automatic voltage regulator (AVR). It is essential that the AVR control be properly set and the generator protection system allow the generator to contribute the maximum reactive power to support the system without exceeding the generator's capability.

#### *B. Voltage Instability*



*Fig. 3 Power System with Remote Generation*

Fig. 3 illustrates a simplified power system with a remote generator supplying a substantial portion of the load at the load center through six transmission lines.  $E_s$  is the voltage at the remote generator buses

and  $E_g$  is the voltage at the load center buses. As lines between the remote generators and the load center trip, the MW power flows over fewer lines resulting in increased VAR losses.

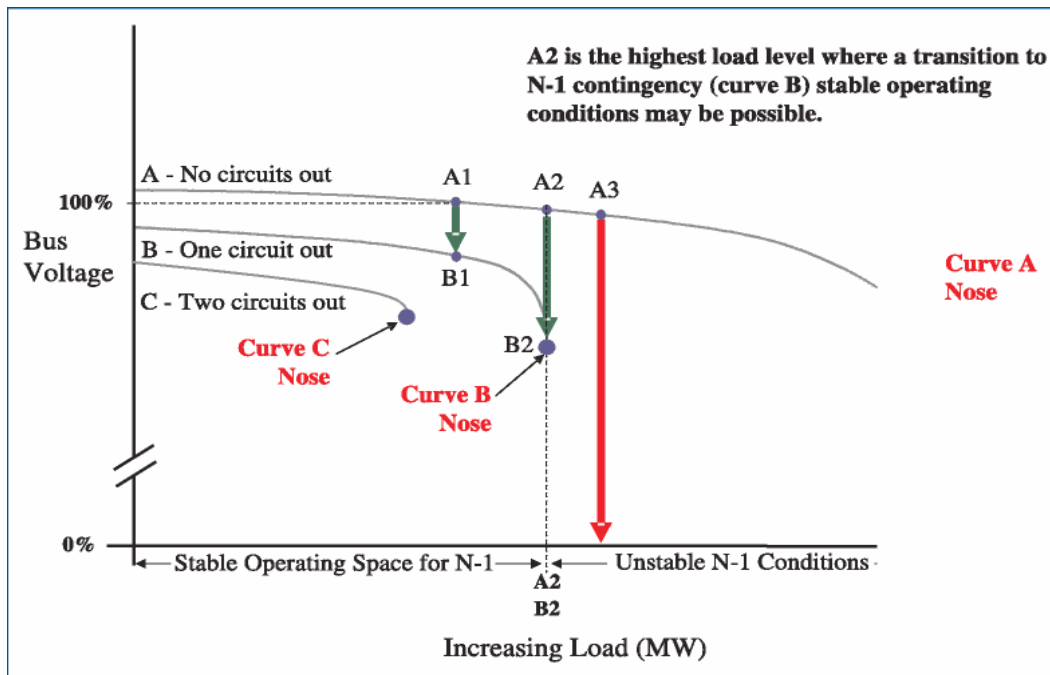


Fig. 4 Real Power (MW) vs. Voltage (P-V) Curve -- Nose Curve

Fig. 4 illustrates how voltage decays as lines trip. This type of P-V analysis (real power relative to voltage) is an analysis tool, used by utility system planners, to determine the real power transfer capability across a transmission interface to supply local load. These curves are also called nose curves by system planning engineers. Starting from a base-case system (all lines in-service), computer-generated load flow cases are run with increasing power transfers while monitoring voltages at critical buses. When power transfers reach a high enough level, a stable voltage cannot be sustained and the system voltage collapses. On a P-V curve (as in Fig. 4), this point is called the “nose” of the curve. The shape of the nose of the curve depends on the nature of the load at the load center. High levels of motor load combined with capacitor bank support of load center voltage tend to make the voltage drop very rapidly for a small increase of power at the nose of the curve. The set of P-V curves illustrates that for baseline conditions shown in curve A, the voltage remains relatively steady (changing along the vertical axis) as local load increases. System conditions are secure and stable to the left of point A1. After a contingency occurs, such as a transmission circuit tripping, the new condition is represented by curve B, with lower voltages (relative to curve A). This is because the power being transmitted from the remote generators now follows through five, rather than six, transmission lines. The system must be operated to stay well inside the load level for the nose of curve B. If the B contingency occurs, then the next worst contingency must be considered. The system operators must increase local generation ( $E_g$ ) to reduce the power being transmitted for the remote generators to reduce losses, as well as increase voltage at the load center to within the safe zone, to avoid going over the nose of curve C.

In the case of the 2003 East Coast blackout [4], three key transmission lines were lost in rapid succession due to faults caused by tree contacts. The voltage at the load center was reduced before the system operators could take effective corrective action. Effective operator action was inhibited by the lack of data from key transmission system substations due to a computer problem at the system operating center. The

loss of the fourth line due to load entering a third zone relay characteristic was the final tripping that triggered the blackout.

In the case described above, voltage decay was relatively slow and there was time for system operator intervention to address the voltage decay problem. There have been cases where the voltage decayed so rapidly that operator action was not possible. These cases involve slow-clearing multi-phase transmission system faults that occur during heat storm conditions when the utility load is primarily made up of air conditioning motors. Due to the extended length of the voltage dip resulting from the slow-clearing transmission system fault, motors in the area began to stall and draw large amounts of reactive power after the fault is cleared. The rapid change in load power factor results in low system voltage as shown in Fig.1. Since there is little reserve of reactive power during peak load periods, the area voltage collapses. Such an event occurred in western Tennessee (Memphis) and resulted in an outage of 1100 MW of load. The entire event took less than 15 seconds [5].

### C. Phase Angle Instability

When the voltage phase angle between remote generators and local generators ( $\theta_g - \theta_s$  in Fig. 3) becomes too large, phase angle instability can occur. In many cases, this event happens in conjunction with the voltage collapse scenario described above. There are two types of phase angle instability.

1) Steady-State Instability: Steady-state instability occurs when there are too few transmission lines to transport power from the generating source to the local load center. Loss of transmission lines into the load center can result in voltage collapse as described above, but it can also result in steady-state phase angle instability.

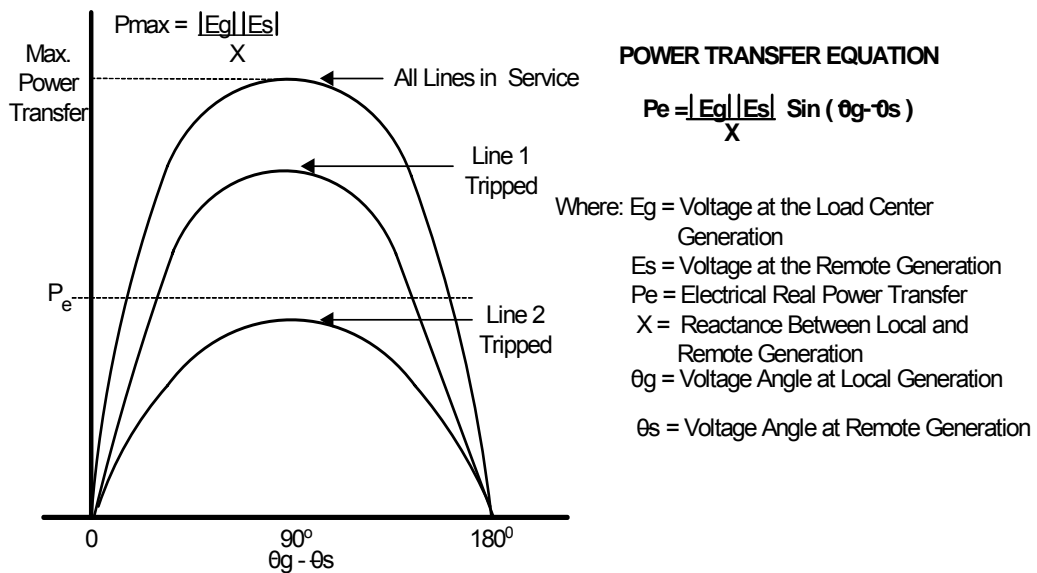


Fig. 5 Power Angle Analysis - Steady-State Instability

Fig. 5 illustrates how steady-state instability occurs. The ability to transfer real (MW) power is described by the power transfer equation and is plotted graphically. From the power transfer equation in Fig. 5, it can be seen that the maximum power ( $P_{max}$ ) that can be transmitted is when  $\theta_g - \theta_s = 90^\circ$ , i.e.  $\sin 90^\circ = 1$ . When the voltage phase angle between local and remote generation increases beyond  $90^\circ$ , the power that can be transmitted is reduced and the system becomes unstable and usually splits apart into islands. If enough lines are tripped between the load center and the remote generation supplying the load center, the reactance ( $X$ ) between these two sources increases, thereby reducing the maximum power ( $P_{max}$ ) that can be transferred. The power angle curve in Fig. 5 illustrates this reduction as line 1 trips the height of the power angle curve and maximum power transfer is reduced because the reactance ( $X$ ) between

the two systems has increased. When line 2 trips, the height of the power angle curve is reduced further to where the power being transferred cannot be maintained and the system goes unstable.

At this point, the power system is in deep trouble. During unstable conditions, the power system breaks up into islands. If there is more load than generation within an island, frequency and voltage go down. If there is more generation than load within an island, frequency and voltage generally go up. Voltage collapse and steady-state instability occur together as transmission line tripping increases the reactance between the load center and remote generation. Generally, the voltage drop at the load center is the leading indicator that the system is in trouble with low frequency occurring only after the system breaks up into islands. Analyses of major blackouts indicate that voltage is more of a leading edge indicator of power system impending collapse. Waiting for the frequency reduction may be waiting too long to shed load to save the system.

2) *Transient Instability*: Voltage phase angle instability can also occur due to slow-clearing transmission system faults. This type of instability is called transient instability. Transient instability occurs when a fault on the transmission system near the generating plant is not cleared rapidly enough to avoid a prolonged unbalance between mechanical and electrical output of the generator. A fault-induced transient instability has not been the cause of any major system blackout in recent years. However, generators need to be protected from damage that can result when transmission system protection is slow to operate.

Relay engineers design transmission system protection to operate faster than a generator can be driven out of synchronism, but failures of protection systems have occurred that resulted in slow-clearing transmission system faults. It is generally accepted [2] that loss-of-synchronism protection at the generator is necessary to avoid machine damage. The larger the generator, the shorter is the time to drive the machine unstable for a system fault. Fig. 6 illustrates a typical breaker-and-a-half power plant substation with a generator and a short circuit on a transmission line near the substation. If the short circuit is three-phase, very little real power (MW) will flow from the generator to the power system until the fault is cleared. The high fault current experienced during the short circuit is primarily reactive or VAr current. From the power transfer equation (Fig. 5), it can be seen that when  $E_g$  drops to almost zero, almost no real power can be transferred to the system. The generator AVR senses the reduced generator terminal voltage and increases the field current to attempt to increase the generator voltage during the fault. The AVR control goes into field-forcing mode where field current is briefly increased beyond steady-state field circuit thermal limits.

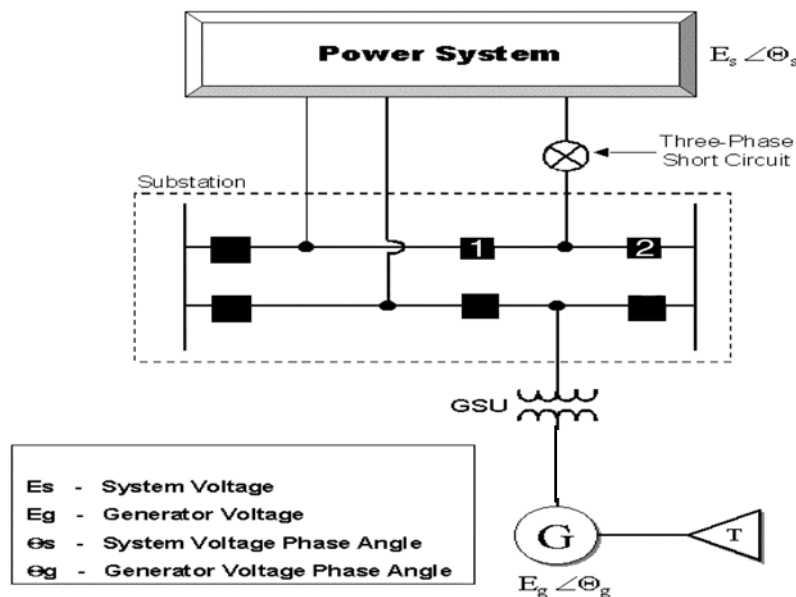


Fig. 6 Typical Large Power Plant One-Line Diagram

During the short circuit, the mechanical turbine power ( $P_M$ ) of the generator remains unchanged. The resulting unbalance between mechanical ( $P_M$ ) and electrical power ( $P_e$ ) manifests itself with the generator accelerating, increasing its voltage phase angle with respect to the system phase angle as illustrated in the power angle plot in Fig. 7.

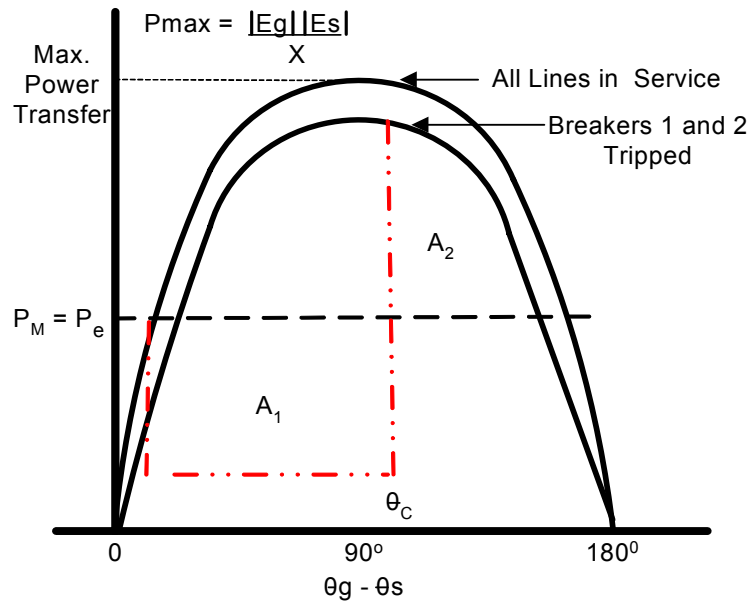


Fig. 7 Power Angle Analysis – Transient Instability

The speed with which the generator accelerates depends on its inertia. The larger the generator, the faster it will accelerate. If the transmission system fault is not cleared quickly enough, the generator phase angle will advance so that it will be driven out of synchronism with the power system.

Computer transient stability studies can be used to establish this critical switching angle and time. The equal area criteria can also be applied to estimate the critical switching angle ( $\theta_c$ ). When area  $A_1 = A_2$  in Fig. 7, the generator is just at the point of losing synchronism with the power system. Note that after opening breakers 1 and 2 to clear the fault, the resulting post-fault power transfer is reduced because of the increase in reactance ( $X$ ) between the generator and the power system. This is due to the loss of the faulted transmission line. In the absence of detailed studies, many users establish the maximum instability angle at  $120^\circ$ . Because of the dynamic nature of the generator to recover during fault conditions, the  $120^\circ$  angle is larger than the  $90^\circ$  instability point for steady-state instability conditions. The time that the fault can be left on the system that corresponds to the critical switching angle is called the “critical switching time.” If the fault is left on longer than that time, the generator will lose synchronism by “slipping a pole.” For this condition, the generator must be tripped to avoid shaft torque damage. Out-of-step protection, which is also called loss-of-synchronism protection (relay function 78), is typically applied on large generators to trip the machine—thereby protecting it from shaft torque damage and avoiding a system cascading event.

#### D. Dynamic Instability

Dynamic instability occurs when a fast-acting generator AVR control amplifies, rather than damps, some small low frequency oscillations that can occur in a power system. This problem has been most often associated with the western region of the U.S. It can, however, occur anywhere the load is remote from the generation. While fast excitation systems are important to improve transient stability as discussed above, a fast-responding excitation system can also contribute a significant amount of negative damping. This reduces the natural

damping torque of the system, causing undamped megawatt oscillations after a disturbance such as a system fault. This type of event can occur if the generator is interconnected to a weak system and loads are far from the generating plant. As discussed, the operation of today's power grid makes this scenario much more likely in many regions of the U.S.

Small signal stability is defined as the ability of the power system to remain stable in the presence of small disturbances most often caused by remote faults. If sufficient damping torque does not exist, the result can be generator rotor angle oscillations of increasing amplitude. When these megawatt oscillations grow, the generator can eventually be driven unstable, lose synchronism and slip a pole. To address this problem, a Power System Stabilizer (PSS) is utilized in conjunction with the generator AVR to provide positive damping when megawatt oscillations occur.

#### **IV. STATUS OF UNDERVOLTAGE LOAD SHEDDING (UVLS)**

Simply stated, the philosophy of UVLS is that when there is a system disturbance and the voltage drops to a pre-selected level for a pre-determined time, then selected loads are shed. The intention is that when load is shed for a disturbance, the voltage will recover to acceptable levels thereby avoiding a more widespread system voltage collapse. Developing a UVLS program requires coordination between protection engineers and system planners, who together can determine the amount of load and time delay required in the shedding program. System planning engineers conduct numerous studies using P-V (nose curves) as well as other analytical methods to determine the amount of load that needs to be shed to retain voltage stability under credible contingencies. Voltage collapse is most probable under heavy load conditions where large amounts of power are to be transported from remote generation sites and the bulk of the system load consists of motors.

Two basic types of UVLS schemes are being applied: decentralized (or distributed) and centralized. A decentralized scheme has relays installed at the loads to be shed. As voltage conditions at these locations begin to collapse, load assigned to that relay is shed. This philosophy is similar to UFLS schemes. A centralized scheme has undervoltage relays installed at key system buses within the area and trip information is transmitted to shed load at various locations. Additional logic is sometimes applied to added security to the system. Many of these schemes are categorized as "special protection" or "wide area" protection schemes. These schemes require high-speed and reliable communication to properly operate.

If voltage collapse is the major cause of power system blackouts, then what is the current status of UVLS and what are NERC's pronouncements on the subject? Implementation of UVLS is not mandatory for NERC member systems. However, NERC has recognized it as a cost-effective method to address voltage collapse. Although most systems studies find UVLS very effective in preventing voltage collapse, it may not benefit all systems. For example, systems with fast voltage decay characteristics (less than a second) may find direct load tripping to be a better alternative. However, systems that are at a risk of fast voltage decay may also be at a risk of slower voltage decay under different conditions. Studies should be performed to determine which systems are the potential candidates for a suitable UVLS scheme. Planning engineers within the regional NERC groups in the U.S. generally conduct these studies.

The most aggressive region in the U.S. that has extensively investigated UVLS is the WECC (Western Electricity Coordinating Council), which has established UVLS guidelines for its members. This regional council serves the western part of the U.S. WECC views automatic UVLS as a safety net to protect the system from collapse or cascading for outages beyond the normal NERC and WECC design criteria.

The WECC has established the following design guidelines in developing UVLS schemes [8]:

1. UVLS should be designed to coordinate with protective devices and control schemes for momentary voltage dips, sustained faults, low voltages caused by stalled air conditioners, etc.
2. The time delay to initiate load dropping should be in seconds, not in cycles. A typical time delay is 3 - 10 seconds.

3. UVLS relays must be on VTs that are connected above automatic LTCs (on the source side).
4. Voltage pick-up points for the tripping signal should be set reasonably higher than the “nose point” of the critical P-V nose curve.
5. Voltage pick-up points and the time delays of the local neighboring systems should be checked and coordinated.
6. Redundancy and enough intelligence should be built into the scheme to ensure reliable operation and to prevent false tripping.
7. Enough load should be shed to bring voltages to minimum operating voltage levels or higher and maintain VAR margin according to WECC’s Voltage Stability Criteria.

System blackouts that were caused by voltage collapse are not confined to the U.S. Major blackouts happened around the world. Blackouts in Italy, Japan, eastern Denmark and southern Sweden have occurred within the last few years and are all related to voltage instability. These and the U.S. blackouts have resulted in utilities beginning to implement UVLS schemes. Table I summarizes a few of the existing UVLS applications at various utilities.

**TABLE I**  
*Existing UVLS Applications [6]*

Utilities	Type	Voltage Collapse Detection	Contingencies
<b>A</b>	De-centralized	- 5% shed load below 90% voltages for 3.5 seconds - 5% shed load below 92% voltages for 5.0 seconds - 5% shed load below 92% voltages for 8.0 seconds	Loss of 500kV double circuit line
<b>B</b>	Two independent centralized PLCs at control centers	- Low voltage at three 230kV S/Ss and high total reactive outputs at generators	500kV voltage collapse
<b>C</b>	EMS based Centralized System	- Low Voltage, Generator Current Limiter, and High Reactive Power detected by relays and signals sent via EMS - Actions are starting Gas Turbine, switching Shunt Reactor, and Load Shedding	
<b>D</b>	U/V relay equipped on potential from line side of breaker at three 230 S/Ss	- 90% voltage	
<b>E</b>	4 subsystems with microprocessor based relay linked via ring communication	- continuous unusual voltage decay at 500kv S/Ss based on $\Delta V / \Delta T$ - 3 out of 5 to detect voltage collapse	extreme contingencies
<b>F</b>	Centralized at two control centers for redundancy	- U/Vs at five S/Ss - 3 out of 5 for bad data rejection	extreme contingencies
<b>G</b>	EMS based centralized system	- 138kv U/V (.93) at 4 out of 5 locations - 138kv U/V (.98) at 4 out of 5 locations & OEL at a unit	Loss of a 345kv line, a 230kv line or a generator with critical generator off-line
<b>H</b>	Centralized PLC at control center	- U/Vs at two 115kv S/Ss for long term - U/V & loss of two 345kv lines for short term	Loss of two 345kv lines
<b>I</b>	De-centralized U/V relays at selected S/Ss	- Single setpoint U/V relays installed at various S/Ss with various time delays - Program sheds 10% of system load	Loss of multiple 345kv lines in northeast Ohio

Some utilities install centralized controllers to receive information like undervoltage (U/V), high reactive output, or loss of lines from remote substations (S/Ss) or power plants and sending initiation signals for load shedding to substations. In other cases, the UVLS function is applied as part of the EMS center program. Others have installed a UVLS program using decentralized undervoltage relays in substations. Sophisticated wide-area controls using signal processing, real-time control computers and phasor measurement are called wide-area protection or special protection schemes.

## **V. DESIGNING A SECURE UVLS SCHEME**

### **A. UVLS vs. UFLS Schemes**

As discussed above, UVLS programs are designed into utility electrical systems to operate as a last resort, under the theory that it is wise to shed some load in a controlled fashion if it can forestall the loss of a great deal of load to an uncontrolled cascading event. There are two kinds of automatic load-shedding installed in North America: undervoltage load shedding—which sheds load to prevent local area voltage collapse, and under-frequency load shedding—which is designed to rebalance load and generation within an electrical island once it has been created by a system disturbance.

Typically, automatic UVLS responds directly to voltage conditions in a local area. UVLS drops several hundred megawatts of load in pre-selected blocks within load centers, triggered in stages when local voltage drops to a designated level—likely 89 to 94%—with a several second delay. The goal of a UVLS scheme is to shed load to restore reactive power relative to demand, to prevent voltage collapse and to contain a voltage problem within a local area rather than allowing it to spread in geography and magnitude. If the first load-shed step does not allow the system to rebalance, and voltage continues to deteriorate, then the next block of load is dropped.

In contrast, automatic under-frequency load shedding (UFLS) is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. By dropping load to match available generation within the island, UFLS is a safety net that helps to prevent the complete blackout of the island, and allows faster system restoration afterward. UFLS is not effective if there is electrical instability or voltage collapse within the island.

Today, UFLS installation is a NERC requirement, designed to shed at least 25-30% of the load in steps within each reliability coordination region. These systems are designed to drop pre-designated customer loads automatically if frequency gets too low (since low frequency indicates too little generation relative to load), starting generally when frequency drops to 59.3 Hz. More load is progressively dropped as frequency levels fall farther. The last step of load shedding is set at the frequency level just above the setpoint for generation under-frequency protection relays (typically 57.5 Hz), to prevent frequency from falling so low that generators could be damaged

### **B. Selection of Voltage Relays for UVLS**

Voltage relays will sense all voltage depressions regardless of cause. Some techniques can be used to improve the ability of undervoltage relays to discriminate between conditions—those that require load shedding, and those that do not [7].

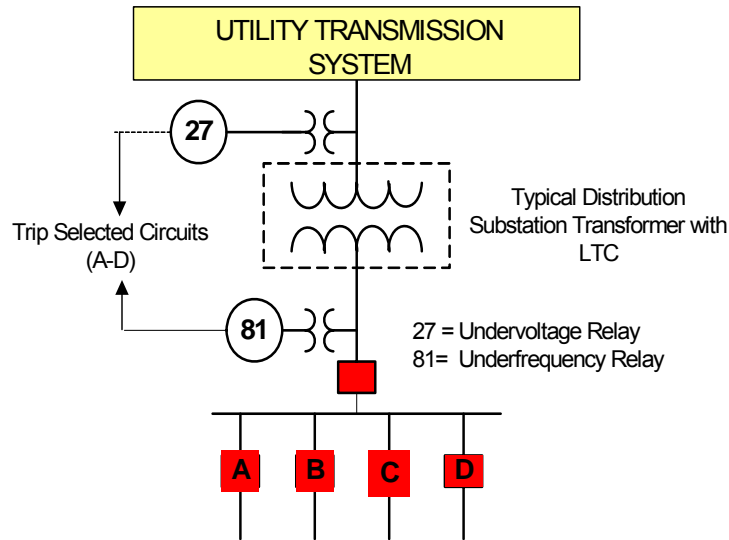
- The relay may measure all three-phase voltages or positive sequence voltage. With this technique, the relay is less likely to respond to unbalanced short circuits.
- The relay may initiate timing only if the measured voltages are within a window, below a maximum level, and above a minimum level to ensure that load will not be shed for accidental loss of signal to the undervoltage relay or for slowly-cleared, three-phase faults which depress the system voltage to less than the minimum level.
- The relay applied must have a high reset ratio. This is necessary so that only a small recovery in voltage level is required to stop the shedding sequence. High accuracy relays are required, with

low setpoint drift. The accuracy of the voltage transformers supplying the relay must also be considered in assessing the overall accuracy of a scheme.

Modern digital relays are an ideal relay to use in undervoltage load shedding application since they have the characteristics cited above.

### C. Secure UVLS Schemes

There are two basic types of automatic UVLS schemes that utilities have installed. Both types involve the installation of undervoltage relays at key utility substations. These relays must measure the transmission system voltage and are typically installed at the primary of distribution substations that are located close to key transmission substations. Fig. 8 shows a typical utility installation of both undervoltage (27) and under frequency (81) relays.



*Fig. 8 Typical Utility Substation Load Shedding*

Because of VT availability, underfrequency relays are usually connected on the secondary of the distribution station because frequency is the same on both the high and low side of the transformer. The voltage measurement for UVLS must be on the transformer primary since transformer losses and load tap changing (LTC) controls will distort the true transmission system voltage level. Fig. 8 illustrates a direct tripping type of UVLS. To add security, some UVLS schemes are only enabled if system conditions have occurred that indicate that the power system is in a “stress condition.” Conditions such as net power import versus local generation or undervoltage measurements at key transmission substation buses are used to arm these UVLS schemes. Some utilities call such schemes “special protection schemes.” These schemes add an additional level of complexity and generally rely on communications to arm the scheme. Also, they may not be armed quickly enough to be activated for undervoltage events caused by slow-clearing, multi-phase transmission system faults that occur during heat storm conditions.

Design of a secure undervoltage separation scheme that avoids false operations for such events as slow clearing system faults requires some logic as well as a relay that can accurately measure voltage within acceptable limits. The undervoltage relay needs to be highly accurate. A measurement accuracy of  $\pm 0.5$  V on a 120 V basis is required. Also, the undervoltage relay that is used needs to have a high pickup/dropout ratio. This ratio needs to be near 100% so that when voltage recovers after a system fault, the relay will quickly reset to the non-trip condition. To meet these requirements, as well as the logic described below, digital relays are almost exclusively being used for UVLS.

Single-Phase UVLS Logic -- Logic can be used to enhance the security of an undervoltage separation scheme to prevent false operation due to slow-clearing system faults. Fig. 9 illustrates a scheme using single-phase, line-to-ground voltage measurements.

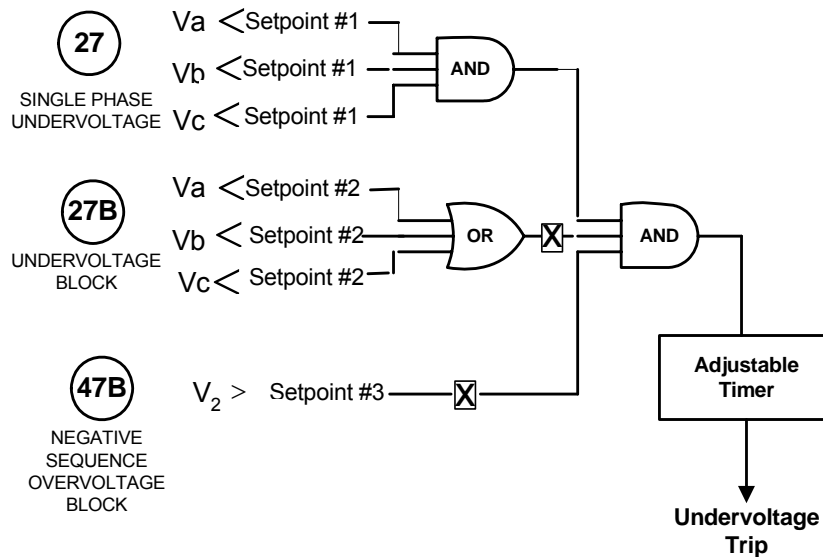


Fig. 9 Single-Phase UVLS Logic

The voltage collapse is generally a balanced voltage event with voltage on all three phases being approximately equal. Fault conditions (with the exception of three-phase faults) result in unbalanced phase voltages. This fundamental difference between low voltages caused by faults versus voltage collapse can be used to add security to a separation scheme. The logic shown in Fig. 9 requires that all three line-to-neutral voltages must drop below setpoint #1. Additional security can be added using undervoltage (27B) blocking. Since the magnitude of undervoltage due to impending voltage collapse is 89-94%, blocking operation for low voltages that are fault-induced adds more security. Fig. 9 indicates that any line-to-neutral phase voltage that drops below setpoint #2 will block the operation of the scheme. The last security measure in the logic scheme in Fig. 9 is the use of negative sequence voltage (47B) to block operation of the separation scheme.

During unbalanced fault conditions (all faults except three-phase faults), negative sequence voltage will be present. Since voltage collapse events are balanced voltage conditions, only a very small level of negative sequence voltage is present. The equation that defines negative sequence voltage is shown below.

$$V_2 = 1/3 ( V_a + a^2V_b + aV_c )$$

Where :  $V_a, V_b, V_c$  are line-to-neutral voltages

$$a = 1\angle 120^\circ$$

$$a^2 = 1\angle 240^\circ$$

To account for the  $120^\circ$  phase angle displacement between phases, unit phasors ( $a$  and  $a^2$ ) are used in symmetrical component terminology. For completely balanced three-phase voltages, the negative sequence voltage is zero. Negative sequence voltage blocking is used to detect unbalanced fault conditions and block the undervoltage scheme from improper operation.

Positive Sequence UVLS Logic -- Another logic scheme to enhance security for voltage separation is shown in Fig. 10.

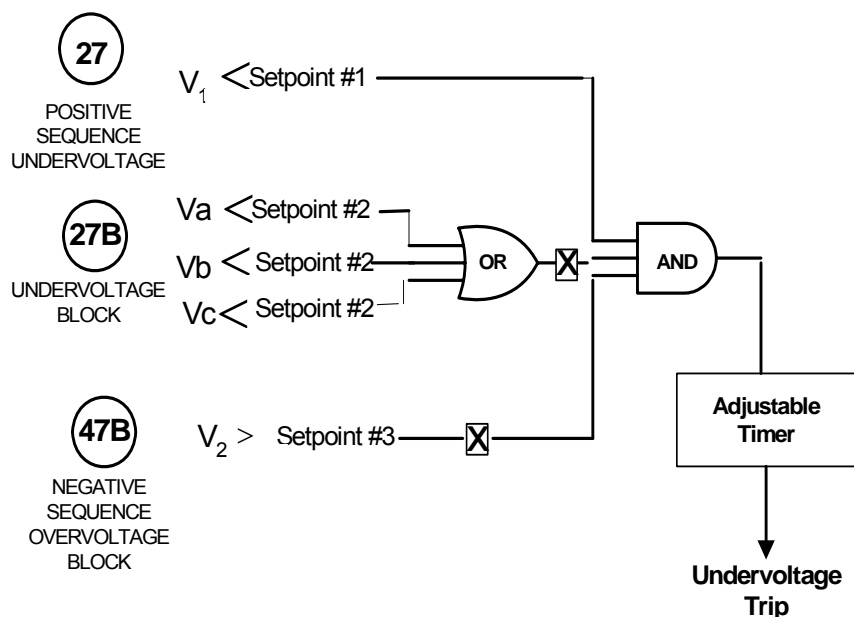


Fig. 10 Positive Sequence UVLS Log

The scheme is similar to that shown in Fig. 9. The blocking elements are the same. But this logic scheme uses positive sequence rather than individual phase-to-neutral voltages to detect an undervoltage condition. Positive sequence voltage is a symmetrical component term and is defined by the following equation:

$$V_1 = 1/3 ( V_a + aV_b + a^2V_c )$$

Where:  $V_a, V_b, V_c$  are line-to-neutral voltages

$$a = 1/120^\circ$$

$$a^2 = 1/240^\circ$$

For completely balanced three-phase voltages, the positive sequence voltage is equal to the value of the normal phase-to-neutral voltages—that is,  $V_1 = V_a = V_b = V_c$ . Positive sequence voltage provides a single quantity as the actuating voltage for undervoltage separation and does not require that all three voltages be below a given setpoint as required in the logic scheme discussed in Fig. 9. Both schemes discussed in Fig. 9 and 10 are easily programmed into modern digital relays. One of the benefits of digital relay logic is that the blocking logic can be modified to suit the user. If undervoltage and/or negative sequence blocking is not desired by the user, it can be easily eliminated in the logic.

Additional security can be provided at critical facilities using a “voting logic” scheme. The “voting logic” means that multiple protective relays are applied with identical settings and logic at the same measuring point on the system. A majority of the devices must agree before action is taken. The purpose of voting logic is to get confirmation of the system conditions from more than one protective relay, thus avoiding potential false tripping based upon a malfunctioning protective relay. If two relays are installed at each location, two-out-of-two logic is used. This logic requires both relays to operate before tripping is initiated. If three relays are used, two-out-of-three logic is used requiring any two relays to confirm the trip condition. Two-out-of-three logic is common in nuclear plant voltage separation schemes.

## VI. UVLS SETTING CONSIDERATIONS

As previously discussed, the setting and design of an UVLS requires close cooperation between the relay engineers and system planners. System planning engineers conduct numerous studies using P-V curves and other analytical methods to determine the amount of load that needs to be shed to retain voltage stability under various contingency conditions. Voltage collapse is most probable under heavy load conditions, so the amount of load to be shed depends on system peak load and generation sources. When considering the type of load to be shed, constant KVA loads such as motors are good candidates for shedding since they draw more current as voltage is decaying. The following is an example that discusses the consideration in setting UVLS relays. The first step is to determine the P-V curves for creditable voltage collapse scenarios.

Fig. 11 shows an example P-V curve for a creditable contingency. The knee of the curve at which the voltage will collapse is identified as  $V_{collapse}$ . A setting margin or safety factor is desired and then the accuracy band of the relay and VT is shown. The setting ( $V_{setting}$ ) must be set above these margins. As with all relay settings, dependability and security need to be balanced. If too small a margin is chosen, there is a risk of the scheme operating during allowable emergency conditions that do not yet require load shedding. If too small a margin is chosen, then load shedding could occur after the system passes below the nose curve voltage collapse point ( $V_{collapse}$ ) shown in Fig. 11.

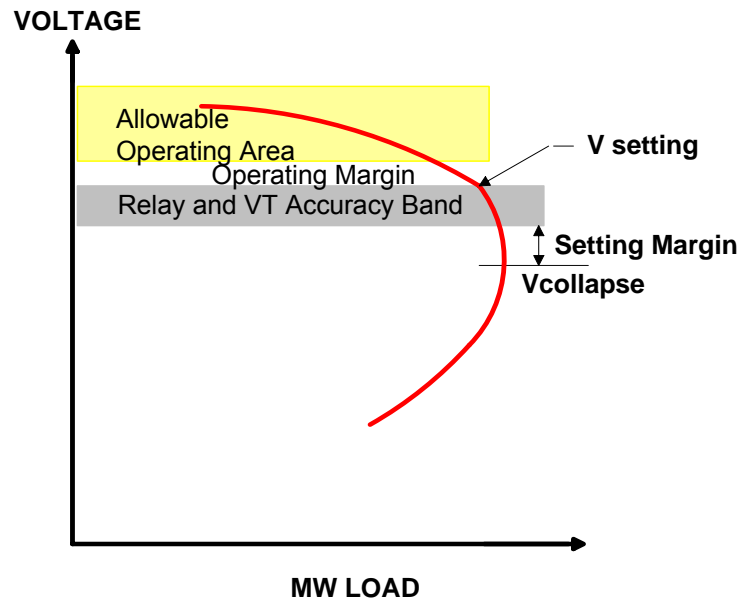


Fig. 11 Example P-V (Nose) Curve

Fig. 12 illustrates this point. The choice of time delay and the number of setpoints are also critical settings, especially for distributive or de-centralized schemes which trip load directly. Again, planning studies can provide help in selecting the time and setpoints. Typically, there are fewer setpoints in UVLS schemes than are used for UFLS. Some utilities have chosen one voltage pickup point with different time delays for each block of load shed. Time delays are generally set at 2 - 10 seconds— not in the cycle range common for UFLS.

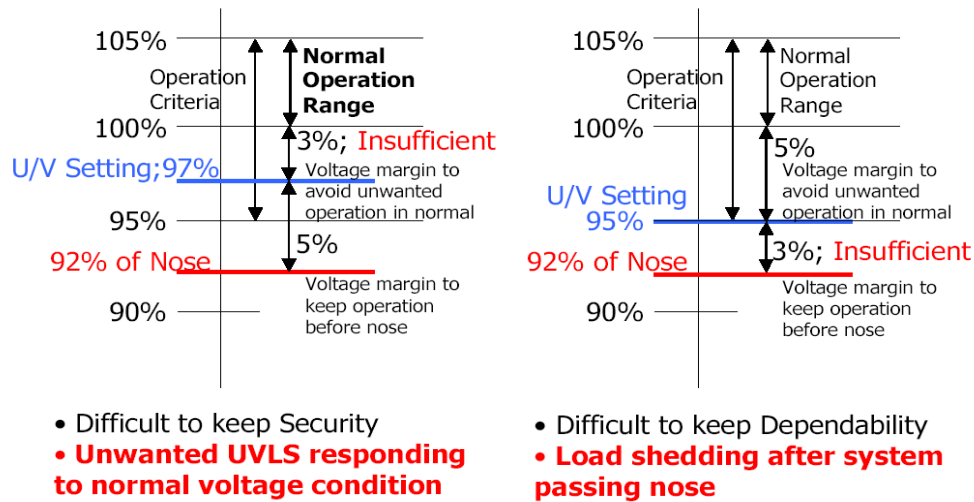


Fig. 12 Difficulties in Coordinating UVLS Pickup Setting

## VII. CONCLUSIONS

Investigations of recent blackouts confirm that the root cause of almost all of these major power system disturbances is voltage collapse rather than the underfrequency conditions prevalent in the blackouts of the 1960's and '70s. The operation of today's power system with load centers remote from the generation source makes today's power system very dependent on the transmission systems that interconnect load and generation. Loss of transmission lines result in high VAR losses that cause voltage collapse at the load center. UVLS is a viable method of providing protection to avoid system voltage collapse. Implementation of UVLS is not mandatory for NERC member systems. However, NERC has recognized it as an important method to address voltage collapse. Although most systems studies find UVLS very effective in preventing voltage collapse, it may not benefit all types of voltage collapse scenarios. For example, systems with fast voltage decay characteristics (less than a second) may find UVLS to be too slow to prevent collapse. UVLS provides a system "safety net" and is an economical method of addressing voltage collapse situations using the philosophy that it is better to shed some load if shedding that load can prevent a much larger outage. Ultimately, however, transmission lines need to be built to address creditable undervoltage conditions.

UVLS schemes are more difficult to design and to set than UFLS and require close cooperation between utility relay engineers and utility system planners. There are two types of UVLS schemes—decentralized (or distributed) and centralized. Both types of schemes are being applied, as individual utilities are beginning to apply UVLS on their own without being mandated to do so by NERC.

This paper discussed the considerations in developing a secure UVLS scheme and it is the hope of the author that it has focused on the key design and setting questions that need to be addressed.

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## ABOUT THE AUTHOR

**Chuck Mozina** is a consultant for Beckwith Electric. He is an active 25-year member of the IEEE Power System Relay Committee (PSRC) and is the past chairman of the Rotating Machinery Subcommittee. He is active in the IEEE IAS I&CPS, PCIC and PPIC committees, which address industrial system protection. He is a former U.S. representative to the CIGRE Study Committee 34 on System Protection and has chaired a CIGRE working group on generator protection. He also chaired the IEEE task force that produced the tutorial “The Protection of Synchronous Generators,” which won the PSRC’s 1997 Outstanding Working Group Award. Chuck is the 1993 recipient of the Power System Relay Committee’s Career Service Award and the 2002 IAS I&CPS Ralph Lee Prize Paper Award. His papers have been republished in the IAS Industrial Applications Magazine.

Chuck has a Bachelor of Science in Electrical Engineering from Purdue University and is a graduate of the eight-month GE Power System Engineering Course. He has authored a number of papers and magazine articles on protective relaying. He has over 25 years of experience as a protection engineer at Centerior Energy, a major investor-owned utility in Cleveland, Ohio where he was the manager of the system protection section. In that capacity, he was responsible for the electrical protection of the company’s generating plants as well as the transmission and distribution system that served over 1.2 million customers. For ten years, he was employed by Beckwith Electric, a manufacturer of protective relays, as Application Manager for Protection Products. He is also a former instructor in the Graduate School of Electrical Engineering at Cleveland State University as well as a registered Professional Engineer in Ohio.